SECTION 5 - ALTERNATIVES TO THE PROJECT

5.1 Alternatives Analyzed

This section discusses alternatives to the proposed Bemidji-Grand Rapids Line: 1) a no-build alternative that focuses on conservation and system operational improvements; 2) a new generation alternative; and 3) transmission line alternatives to the Project. The section explains why all these alternatives are unacceptable or less than optimal in comparison with the Project.

5.2 No-Build Alternative

The initial consideration in addressing the reliability of a transmission system strained by increasing load growth is whether both load growth and existing electrical system facilities can be managed to avoid altogether building additional facilities to handle the projected growth. The following discussion of the “no-build” alternative focuses on how the use of load management and conservation measures to limit energy load growth, and the improvement of local reactive power supply to enable the current transmission system to handle the increase in energy demand are not measures that can successfully address the projected growth in energy demand in the Bemidji area and the North Zone of the Red River Valley over the long term.

5.2.1 Demand Side Management and Conservation Measures

Pursuant to Minn. Stat. § 216B.2422, each of the Utilities have recently submitted a Resource Plan for review by the Commission. These Resource Plans detail, among other things, the Utilities’ programs to control customer loads. Each of these “demand side management” programs are directed at minimizing the peak load at any given moment by reducing or eliminating the load of certain customers at certain times. The Utilities have also instituted additional Conservation Improvement Programs (“CIP”) as part of their latest Resource Plans. These programs focus on increased efficiencies that reduce the amount of energy needed for certain uses.

The projected load of 296 MW in 2011/2012 for the Bemidji area assumes the Utilities will be successful in reaching the DSM and CIP energy savings identified in their respective Resource Plans. Thus even greater reductions would have to be achieved for DSM and CIP to be feasible alternatives to the Project. As discussed in subsection 5.3.3 below, 76 MW of local running generation would have to be added to the Bemidji area if new transmission is not built, and thus a comparable reduction of load would have to be achieved by 2011/2012 if neither transmission nor generation were built. As discussed in Section 4.10 above, it is not realistic to expect that DSM and CIP measures could both achieve that level of reduction and do so within the specific geographic area that is necessary. Pursuant to the Commission’s Data Exemption Order, additional information on the Utilities’ DSM and CIP programs is provided in Appendix F.

5.2.2 Reactive Power Supply

Presently, energy demand in the Bemidji area is met primarily by remote generation via the bulk transmission system. The Bemidji area now only has one local generating facility: Otter Tail Power’s Solway Generating Station located in Lammers Township, Minnesota; which is a

40 MW dual-fuel (natural gas and oil) peaking generator with the ability to operate as a synchronous condenser (dynamic reactive power supply source).[1] The current load-serving capability of the Bemidji area is limited by voltage stability concerns following the loss of one of the transmission sources into the area. The present system has a maximum load-serving capability of approximately 220 MW, which is projected to be 76 MW less than the anticipated peak load of 296 MW in the 2011/2012 winter season (when the Bemidji-Grand Rapids Line is expected to be in service). The limiting contingency is the loss of the Winger-Wilton 230 kV line. The location of greatest concern for voltage collapse following this contingency is Cass Lake, which is southeast of Bemidji.

Until the end of 2011, first-contingency requirements to maintain a reliable transmission system can be satisfied with the addition of capacitor banks at the Wilton or Cass Lake Substations, and forced operation of the Solway generation unit. As a result, Otter Tail Power plans to install capacitor banks at Cass Lake. By the end of 2011, however, the ability to improve system support using capacitors and the Solway generator will be reached.

Double-contingency (N-2) analysis, which focuses on the loss of two critical facilities simultaneously, was conducted to determine the reactive power requirements of the Bemidji area between the years 2006 and 2011.[2] Although the addition of capacitors effectively addresses system performance concerns for a number of second-contingency scenarios, it does not fully address all concerns. In many of the second-contingency scenarios, severe line overloading is evident, so even with ample reactive power supplies available the area's load serving capability is still constrained. Consequently, load shedding must be employed to prevent line overloading during various second-contingency scenarios.

The operation of the 40 MW Solway peaking generator helps improve system performance for most of the contingencies analyzed. However, this requires dispatch of Solway before the contingency occurs. This generator does not help for any scenarios involving the loss of the Solway-Wilton 115 kV line, which separates the generation from critical portions of the Bemidji load center, such as the city of Bemidji, and the Cass Lake area.

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[1] Formerly there were two generating facilities in the Bemidji area. In September 2006, however, Ainsworth Engineered USA cut in half its production of wood products and shut down its generation facility located near Cass Lake. The loss of 11.5 MW of generation (and its associated reactive support to the system) with only a 4.5 MW reduction in load places a greater burden on the local transmission system. While the analysis of the Bemidji area has not been updated to quantify the impact of this specific loss of local generation, system performance has been slightly degraded beyond what existing study results show.

[2] The standards established by the North American Electric Reliability Council ("NERC"), which develops and enforces reliability standards to improve the reliability and security of the bulk power system in North America, require consideration of N-2 conditions. See NERC Standard TPL-003-0, Category C (requiring analysis of "event(s) resulting in the loss of two or more (multiple) elements").

As the 2011/2012 timeframe approaches, Solway will have to be run as a generator for increasing lengths of time on a pre-contingent basis to maintain a reliable transmission system. This is costly, and the Solway generation was not designed or intended to be operated in this manner. It is limited in how long it can be run, based on fuel supply, the amount of purified cooling water available, and its operational permits. Even with the Solway generator running at full power, and the aforementioned capacitor additions at the Wilton and Cass Lake Substations, the transmission system in the Bemidji area will not have a load-serving capability equal to the projected 2011/2012 winter peak demand of 296 MW. By this time the system's voltage stability concerns will need to be addressed by the addition of new transmission or generation in the area.

System operation beyond the voltage stability limit will result in voltage collapse, evidenced by sustained under-voltages leading to tripping of sensitive loads and reduced life of motors in appliances (refrigerators, furnaces, air conditioners, *etc.*). These concerns cannot be reliably addressed by more capacitors because when load levels approach the voltage stability limit and system collapse, capacitor switching results in unacceptably large voltage changes that can result in voltage spikes above acceptable limits. In addition, it is difficult to coordinate automatic controls for the capacitor banks at the higher load levels.

5.2.3 Conclusion on No-Build Alternative

The Utilities have and continue to execute DSM and conservation improvement programs to manage the growth of load in the Bemidji area. The forecasted 296 MW winter peak load by 2011/2012 already incorporates the energy savings that can be expected to be realized under these programs. Increasing DSM and conservation efforts is therefore not a realistic alternative to new transmission or generation to address the area's increasing demand for energy.

The Utilities have also been upgrading existing facilities in the area to meet the increase in demand. The addition of reactive support to area substations, and the increased operation of area peaking generation, will help maintain system load-serving capability up to 2011/2012, at which point future load growth will require additional transmission or generation.

5.3 Generation Alternative

Addition of generation near the load center is a theoretical alternative for improving the power system's load serving capability. This section discusses the practicality of adding new generation to secure increases in the Bemidji area and Red River Valley load-serving capability, considering relevant reliability and economic factors.

5.3.1 Type of Generation Required

Generation can be characterized as either baseload, intermediate, or peaking. Within each type, the generation can be characterized as dispatchable (*i.e.*, available upon demand) or non-dispatchable (*i.e.*, not necessarily available upon demand). For the Bemidji area, generation output would need to be dispatchable or well correlated with the load level because there is limited transmission capacity for importing energy from other regional generation. Consequently, intermittent resources such as wind generation would not be feasible stand-alone solutions.

Baseload generation typically has a high installed cost and low operating costs. Typical units of this type are coal-fired, nuclear, or hydro. The unit is expensive to construct but uses inexpensive fuel, and has relatively high efficiency. Due to strong economies of scale, baseload units generally have 400 to 1000 MW capacities.

In contrast, peaking generation additions have relatively low installed cost but high operating costs. Typical units of this type are gas- or oil-fired combustion turbines. The unit is relatively inexpensive to construct but consumes expensive fuel. Peaking generators such as combustion turbines are commonly available in sizes from 20 MW to 200 MW.

In between the extremes of baseload and peaking generation is intermediate generation. Typical units of this type are "combined-cycle" arrangements consisting of one or two gas-fired combustion turbines with a heat recovery steam generator powering a conventional steam turbine-generator. This blending of technologies captures the low installed cost of the combustion turbine plus the additional efficiency gained from a steam cycle unit, whose input is recovered waste heat from the combustion turbines. However, fuel costs for gas-fired intermediate generation are higher and more volatile, significantly impacting the cost of generation, especially during the winter season when the high demand for gas for home heating affects gas availability and pricing.

In the end, the feasibility of gas-fired generation, even with the economic benefits of intermediate generation efficiency, is not a prudent alternative. Natural gas prices are at their highest during the winter heating season when loads within the Red River Valley are at their highest levels during the year.

5.3.2 Transmission Outlet Requirements

As discussed in subsection 4.8.3 above, the Bemidji area is "inside" the NDEX boundary. Although the Bemidji area is generation-poor, the NDEX region in which it is located is, as a whole, generation-rich. Addition of new generation in a generation-rich area requires either that existing generation within the area be displaced, or that increased transmission outlet capability be established to allow continued operation of the existing generation.

The existing North Dakota generation is characterized by very low production costs because it is nearly all baseload. Consequently, displacement of existing generation is not desirable because displacement of low-cost generation will increase total system production costs.

Since the NDEX boundary is a power transfer-limited interface, adding new generation within its boundaries would require transmission additions to increase the existing generation outlet capability. New lines constructed to provide the outlet capability for new generation would be similar in length and voltage to the proposed Fargo-Twin Cities and Bemidji-Grand Rapids Lines, whose installation the generation addition is trying to avoid.

5.3.3 Installed Generation at a Single Site

In order for a generation addition to the Bemidji area transmission system to provide system reliability enhancement equivalent to that achieved by the addition of a transmission line, the generating facility must be as reliable as the line would be. Based on industry experience of "forced" (unplanned) line unavailability being generally in the range of 1-9 hours per year, a new transmission line can be expected to have an annual availability factor of over 99.9%.

Generators typically have availability in the range of 85% to 95%. It is therefore impossible for the addition of one generating unit to provide service equivalent to that provided by addition of one transmission line. With a generating unit availability in the range of 85% to 95% it is necessary to have four generators each with an 86% availability, or three generators each with a 93% availability, to achieve generation availability equivalent to that of one transmission line.

The current forecast shows that the projected peak load in the Bemidji area is 76 MW greater than the projected 220 MW maximum load-serving capability of the existing transmission system in 2011 under single-contingency circumstances. In order for generation to eliminate the need for transmission, a minimum of 76 MW of generation would need to be running prior to any contingency or other disturbance on the transmission system. As explained above, more than one generator is required to insure that 76 MW of generation is always available when needed. For the purposes of this analysis, the 40 MW Solway generator was not considered as a source to supply the required generation on a long-term basis since it has numerous restrictions on its availability, as explained in subsection 5.2.2 above. Although the availability of the Solway generator could be improved by upgrading it and its ancillary facilities at a significant capital cost, the generator's operational permits may not be able to be modified. Therefore the installation of three combustion turbine units of 60 MW each was assumed in this analysis. This would provide redundancy as well as support for expected load growth.

At $700/kW installed, these three units would cost approximately $126 million. This assumes suitable sites and fuel delivery arrangements could be secured. In the case of load centers subject to post-contingent voltage collapse, as is the case in the Bemidji area, up to two of the local generating units would need to be on line pre-contingency during high load conditions, displacing power which would have otherwise come from remote generation resources. The remote generators will as a group have lower energy production costs during nearly all of the hours involved, so system production cost penalties will be accumulated each year. Based on capital cost alone, generation is not a viable alternative to the Project.

5.3.4 Distributed Generation

While there is no universally accepted definition of "distributed generation," the Institute of Electrical and Electronics Engineers defines it as a resource having an aggregate capacity of 10 MVA or less that is not directly connected to a bulk power transmission system. See also Minn. Stat. § 216B.169, subd. 1(c) (defining the term "high-efficiency, low-emissions, distributed generation" as a distributed generation facility of no more than ten megawatts of interconnected capacity that is certified as a high-efficiency, low-emissions facility). Many different fuel types can be used to power distributed generation, including natural gas, propane, oil, wind, biomass, etc., although it is unlikely that units powered by oil would meet the statutory definition.

As discussed above, by the winter of 2011/2012 a minimum of 76 MW of dispatchable distributed generation would have to be installed in the Bemidji area and kept on-line on a pre-contingency basis to eliminate the need for additional transmission. Just as with central station generators discussed above, additional distributed generation would be required to insure that a minimum of 76 MW would always be available. Distributed generation resources are also typically unmanned and this must be taken into account when assessing the availability and reliability of this alternative.

For the purposes of this analysis, it is assumed that initially 110 MW of dispatchable distributed generation would be required to provide the redundancy necessary to ensure that at least 76 MW would be available at all times. Additional generation beyond the 110 MW would be needed to keep up with growth in the area's load beyond 2011/2012. Because a distributed generator's aggregate capacity at each site must remain below 10 MW, a minimum of eleven sites each with 10 MW of generation would need to be identified. These sites would all have to be 1) strategically located at points in the power system where the generation will support the transmission system's voltage without exceeding its thermal limits; 2) not require extensive transmission upgrades which would defeat the purpose of adding distributed generation in lieu of the new transmission; and 3) be close to a fuel source to minimize supply costs. Typically it is very difficult to achieve all three goals. In addition, more sites would ultimately need to be located to keep up with projected load growth.

Generally a 10 MW distributed generation site would have several 1.5 to 2 MW generators driven by reciprocating engines, powered by diesel fuel. Assuming diesel generators rated at 2 MW output, 5 generators would be needed at each of the eleven sites for a total of 55 generators.

The typical installed cost of a 10 MW distributed generation site connected to a 69 kV or lower voltage power line would be approximately $7,650,000 for five 2 MW diesel reciprocating engines, or $84,150,000 for the eleven sites. However, since the continuous rating of this type of generator is typically only 85% of the peak rating or 1.7 MW per generator, the total continuous capability at each site would be 8.5 MW. The additional cost to construct communications to the site would further increase the cost of this alternative. At a minimum, this would involve installation of dedicated leased phone lines, the cost of which is highly dependent on location. Recent quotes received by Minnesota Power for dedicated leased lines have been approximately $100,000 per mile, with a $1000 per month lease charge.

Diesel generators are expensive to run and maintain. Typical diesel fuel consumption is over 100 gallons per hour per engine (or $175/MWh with diesel at $3 per gallon) when the engines are operated at their continuous rating. That would be approximately 8,000 gallons over a continuous 16-hour run period for each 10 MW site. The $7.65 million cost estimate per site is for the five generators, and a 10,000 gallon fuel tank to supply the five units, which means that the units may need to be fueled on a daily basis during peak load periods. In addition, permit restrictions may limit the number of hours a diesel powered generator could be operated due to emission requirements. This may mean that these units would not be a viable alternative unless appropriate permits can be obtained.

Use of natural gas powered reciprocating engines could eliminate the fuel supply issues associated with diesel fuel. They may also reduce issues associated with air emissions and air quality permits. However the cost would increase significantly for two reasons. First, an engine modified to run on natural gas is typically de-rated by approximately 50% so the number of generators would double as would the installation cost. Second, the cost to bring a natural gas supply to the site is approximately $300,000 per mile, and depending on the location, this could become cost prohibitive. Finally, there would also be the same natural gas fuel availability and operational cost issues identified in subsection 5.3.1 above. Thus the use of natural gas instead of diesel generators does not appear to be reasonable.

Another alternative would be to install a single 10 MW gas or oil combustion turbine at each site. However, turbines are more expensive than reciprocating generators so this alternative would have a higher initial cost. Depending on location, these units would likely be fueled by natural gas or diesel fuel and therefore have the same fuel availability and operational cost issues discussed above. Also, these units would probably not meet the requirements of a high-efficiency low-emissions resource as defined in Minnesota statute.

The typical cost of a small natural gas combustion turbine is approximately $1,105/kW installed, or $11,050,000 per 10 MW site. This would bring the total cost for eleven sites to $121,550,000 which is more than double the estimated cost to construct the Project. This cost would be further increased by the cost to interconnect the generator to the power system, and get communications and a gas supply to the site. Again this does not appear to be a reasonable alternative due to the high capital cost.

5.3.5 Conclusion on Generation Alternative

Adding generation in the Bemidji area is not a practical method of achieving the required power system load serving capability in lieu of transmission line additions. This is primarily due to the following considerations:

- the Bemidji area is electrically on the generation-rich side of the constrained NDEX boundary, and thus the addition of local generation would displace rather than supplement lower-cost remote generation;

- the relatively low reliability (*i.e.*, availability) of generation compared to that of transmission lines;

- the capital investment required for intermediate generation would be of a magnitude much greater than the transmission facilities they are intended to supplant; and

- the cost of running additional local generation in anticipation of a transmission outage would be significant.

Considering all the above information, installation of local generation or distributed generation in the Bemidji area is not a practical or cost-effective alternative to the construction of the Project.

5.4 Transmission System Alternatives

The Utilities' evaluation process demonstrated that new transmission was the best option to address the area's load-serving deficiency. The Utilities evaluated different transmission line alternatives to determine the optimal new transmission alternative to meet the needs of the Bemidji area in particular, as well as the North Zone of the Red River Valley region as a whole.

5.4.1 Transmission Alternatives Evaluated

The Utilities evaluated four new transmission alternatives:

1. Add a Bemidji-Grand Rapids 230 kV line (from Wilton Substation to Boswell Energy Center Substation);

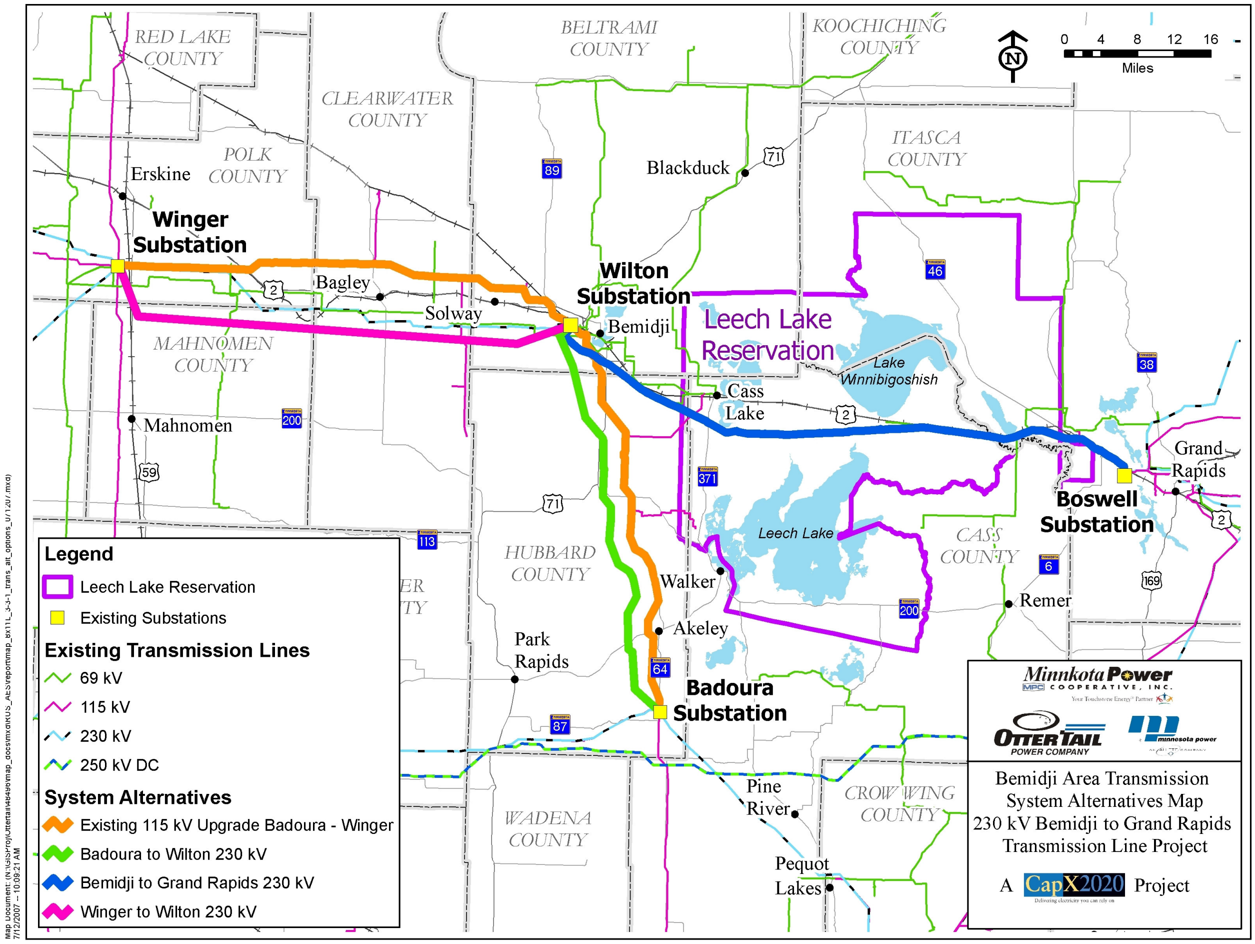
2. Add a second Winger-Wilton 230 line on separate structures from the existing 230 kV line;

3. Add a Badoura-Wilton 230 kV line on separate structures from the existing 115 kV line; and

4. Rebuild the existing 115 kV Bemidji area lines (Badoura-Wilton and Winger-Wilton) to higher capacity (300 MVA).

Figure 5.4-1 below illustrates the four alternatives.

Figure 5.4-1 Transmission Alternatives



The four alternatives were evaluated to determine which was optimal based on the following analyses: 1) voltage stability (also known as Power-Voltage or P-V) analysis; 2) thermal (line and transformer loading limit) analysis; 3) demand and energy loss analysis; and 4) total cost of ownership analysis. The results from these various analyses are discussed in the following subsections.

5.4.2 Voltage Stability and Thermal Limit Analyses

To determine the incremental load-serving capability that each transmission alternative provided the North Zone, a voltage stability (P-V) analysis was done to examine voltage adequacy as load increases, and a thermal limit analysis was done to determine at what point line or transformer overloads (thermal constraints) are experienced as load increases. The P-V and thermal limits for the Bemidji-Grand Rapids Line are discussed above in subsections 4.8.1 and 4.8.2. The P-V and thermal limit analysis below include all of the other transmission alternatives as well, with each alternative analyzed under pre-contingency conditions (*i.e.*, system intact), and after each of the following critical contingencies occurred: a) outage of the Dorsey-Forbes 500 kV line; b) outage of the Wilton-Winger 230 kV line; and (c) coincident outages of the Wilton-Winger 230 kV line and Badoura-Laporte 115 kV line. As noted in Section 4.8, these were identified as the most limiting contingencies in the transmission studies conducted by the Utilities.

(a) Voltage Stability Analysis Results

As demonstrated by Table 5.4-1 below, the load-serving limits of the North Zone of the Red River Valley as determined by P-V analysis are very different among the various transmission alternatives. All yield at least 290 MW of incremental load serving capability as compared to 230 MW for the existing system.

Table 5.4-1 North Zone Voltage Stability Limits With Each Transmission Alternative
(Incremental Load-Serving Capability of Red River Valley North Zone Based on 2003/2004 Winter Peak Load of 850 MW)

Condition	Existing System	Bemidji-Grand Rapids 230 kV Line	Winger-Wilton 230 kV Line #2	Badoura-Wilton 230 kV Line	Rebuild Existing 115 kV Lines
	Load Limit (MW)				
System Intact	525	805	610	650	585
Dorsey-Forbes outage	300	450	290	370	350
Wilton-Winger outage	230	780	525	590	315
Wilton-Winger & Badoura-LaPorte outage	No solution*	560	415	515	No solution*

* Infeasible condition due to voltage collapse.

The shaded cells in Table 5.4.1 indicate the contingency that establishes the load-serving limit for each transmission alternative. As can be seen, the limiting contingency for the 115 kV Line Rebuild alternative is the Wilton-Winger outage. All other alternatives perform better for that contingency. The limiting contingency for the other three alternatives is the Dorsey-Forbes outage, with the Bemidji-Grand Rapids Line increasing the system capability during that contingency the most: from 300 MW to 450 MW.

The table also shows that the Bemidji-Grand Rapids Line is the best performer following the limiting double contingency of the Wilton-Winger & Badoura-LaPorte outage, with a capability of 560 MW. The rebuild of existing 115 kV lines offers no incremental load-serving capability in the event of a double contingency.

(b) Thermal Analysis Results

Table 5.4-2 below indicates the best transmission alternatives for increasing the load-serving capability of the North Zone of the Red River Valley based on post-contingent line loading (thermal) concerns are the Bemidji-Grand Rapids and Badoura-Wilton 230 kV Lines. These are also the alternatives with the best voltage stability performance, as discussed above. The worst alternative is the Winger-Wilton 230 kV Line #2 (*e.g.*, a 25 MW thermal limit for the Dorsey-Forbes outage). The rebuild of existing 115 kV lines also performs relatively poorly (a 75 MW thermal limit for the Dorsey-Forbes outage).

Table 5.4-2 North Zone Thermal Limits With Each Transmission Alternative
(Incremental Load-Serving Capability of Red River Valley North Zone Based on 2003/2004 Winter Peak Load of 850 MW)

Condition	Existing System	Bemidji-Grand Rapids 230 kV Line	Winger-Wilton 230 kV Line #2	Badoura-Wilton 230 kV Line	Rebuild Existing 115 kV Lines
	Load Limit (MW)				
System Intact	350	500	400	500	500
Dorsey-Forbes outage	0	275	25	200	75
Wilton-Winger outage	100	500	350	500	300
Wilton-Winger & Badoura-LaPorte outage	No solution*	500	500	500	No solution*

* Infeasible condition due to voltage collapse

Taken together, the voltage stability (P-V) and thermal analyses show that the best alternative for providing significant increases in load-serving capability in the North Zone of the Red River Valley (where Bemidji is located) is the Bemidji-Grand Rapids Line. The Bemidji-Grand Rapids Line alternative has superior electrical performance based on the voltage stability and thermal analyses summarized above.

It is important to choose the alternative that provides the best performance in order to maximize the number of years before the next improvement will be needed. Given the alternatives presented above, choosing any alternative other than the Bemidji-Grand Rapids Line will result in additional load-serving improvements being required sooner in the North Zone.

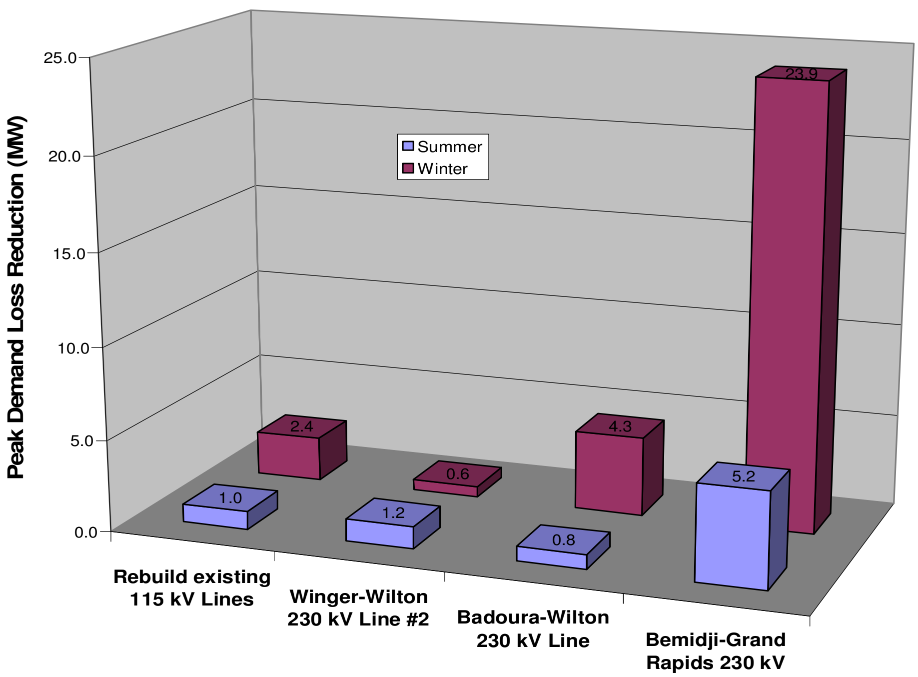
5.4.3 Transmission Demand and Energy Loss Analyses

Transmission losses consist of demand (MW) and energy (MWh) losses. The Utilities analyzed the ability of each of the four new transmission alternatives to reduce such losses from the levels experienced for the existing system.

(a) Demand Loss Analysis

Both summer and winter demand losses for the existing system were calculated. Then the reduction of those losses achieved by each of the four alternatives was calculated. The results are provided in Figure 5.4-2 below, which shows that the Bemidji-Grand Rapids Line significantly reduces demand losses over any of the other alternatives.

Figure 5.4-2 Demand Loss Reductions for Each Transmission Alternative



While the upper Midwestern U.S. is strongly summer peaking, the customer load in the northern Red River Valley and the Bemidji area is winter peaking. Thus the reduction in demand losses is greatest during the winter.

The above annual demand loss reduction was then translated into capacity-related cost savings, assuming that the capacity savings associated with each alternative represents an avoided installation of peaking generation capacity. Because the region as a whole is summer peaking, winter peak loss reductions do not represent incremental avoided capacity. The value of capacity savings of the alternatives are therefore based on summer demand loss reduction. The capacity value is calculated based on 115% of the actual demand loss reduction (to cover the reserve sharing pool capacity obligation), an installed cost of $700/kW for the avoided generation, and an annual fixed charge rate of 11.92%. The capacity cost savings from each alternative's annual demand loss reduction is provided below in Table 5.4-3.

Table 5.4-3 Annual Capacity Savings From Demand Loss Reduction for Each Transmission Alternative
Eastern Interconnection

Transmission Alternative	Peak Summer Demand Loss Reduction (MW)	Capacity Savings ($ Thousands)
Bemidji-Grand Rapids 230 kV Line	5.2	$499
Winger-Wilton 230 kV Line #2	1.2	$115
Badoura-Wilton 230 kV Line	0.8	$ 77
Rebuild Existing 115 kV Lines	1.0	$ 96

The value of the capacity savings associated with the Bemidji-Grand Rapids Line is over four times that of the alternative with the next greatest savings, and over six times greater than the Badoura-Wilton alternative.

(b) Energy Loss Analysis

The amount of the reduction in winter peak demand losses is used to derive the energy losses associated with each of the transmission alternatives. Basing the energy losses on the winter peak demand losses is appropriate because energy consumption in the Bemidji area is greatest during the winter season. Furthermore engineering formulas used to estimate average annual energy losses are based on peak loss values. Upon calculating the loss factor for the area transmission system, it is then applied to the winter peak demand loss reduction and multiplied by the number of hours per year to obtain the annual energy loss savings in MWh. This is then converted to a dollar value by applying an assumed average annual energy cost of $50 per MWh for replacement energy from existing regional generation resources, based on the average MISO price for energy at the Minnesota hub in 2007. The results are shown in Table 5.4-4 below.

Table 5.4-4 Annual Energy Loss Savings for Each Transmission Alternative

Transmission Alternative	Winter Peak Loss Reduction (MW)	Loss Factor (%)	Equivalent Hourly Loss Savings (MW)	Annual Loss Savings (MWh)	Annual Loss Savings @ $50/MWh ($ thousands)
Bemidji-Grand Rapids 230 kV Line	23.9	41.5	9.92	86,886	$4,344
Winger-Wilton 230 kV Line #2	0.6	41.5	0.25	2,181	$ 109
Badoura-Wilton 230 kV Line	4.3	41.5	1.78	15,632	$ 782
Rebuild existing 115 kV Lines	2.4	41.5	1.00	8,725	$ 436

The annual energy loss savings resulting from the Bemidji-Grand Rapids Line is estimated to be over $4 million per year. All other transmission alternatives yield less than 20% of the savings achieved by the Bemidji-Grand Rapids Line.

(c) Cumulative Demand and Energy Loss Savings

The cumulative lifetime economic value of the demand and energy loss reductions was calculated for each transmission alternative assuming a 40-year period for the duration of the loss differences, and a discount rate of 7.49% per year. Table 5.4-5 below shows the present value of the demand and energy losses for each transmission alternative.

Table 5.4-5 Annual and 40-Year Cumulative Present Value of Loss Reductions for Each Transmission Alternative

Transmission Alternative	Annual Savings ($ Thousands)			Cumulative Present Value ($ Millions)
	Demand Savings	Energy Savings	Total Savings	
Bemidji-Grand Rapids 230 kV Line	$ 499	$ 4,344	$ 4,843	$ 31.9
Winger-Wilton 230 kV Line #2	$ 115	$ 109	$ 224	$ 1.7
Badoura-Wilton 230 kV Line	$ 77	$ 782	$ 858	$ 5.6
Rebuild existing 115 kV Lines	$ 96	$ 436	$ 532	$ 3.6

The Bemidji-Grand Rapids Line yields significantly higher loss savings than any of the other alternatives. (*i.e.*, nearly 6 times greater than the Badoura-Wilton 230 kV Line, which has the next highest loss savings.)

5.4.4 Total Cost Analysis

A final economic analysis was performed to determine whether the impact of the differences in loss savings among the four transmission alternatives is significantly reduced when one considers the alternatives' construction costs. For this analysis, each transmission alternative's cumulative present value of revenue requirements was calculated based on the construction costs for the alternative, the alternative's loss savings, the levelized annual revenue requirement (LARR) factor for the alternative, a discount rate of 7.49% per year, and an assumed life for the facilities of 40 years. The construction cost for a 230 kV line is estimated to be between $675,000 and $915,000 per mile, depending on the terrain crossed and excluding right-of-way, permitting, and other ancillary costs. Table 5.4-6 below shows the transmission alternatives' present value revenue requirements.

Table 5.4-6 Cumulative Present Value of Revenue Requirements (PVRR) for Each Transmission Alternative
(Including Value of 40-Year Loss Savings)

Transmission Alternative	Installed Cost ($ millions)	Cumulative PVRR ($ million)		
		Capital Related PVRR	Loss Savings	Net PVRR
Bemidji-Grand Rapids 230 kV Line (68 miles with 2 substation upgrades)	$ 58	$ 117	-$32	$ 85
Winger- Wilton 230 kV Line #2 (53 miles with 2 substation upgrades)	$ 46	$ 93	-$ 2	$ 92
Badoura-Wilton 230 kV Line (48 miles with 2 substation upgrades)	$ 42	$ 86	-$ 6	$ 80
Rebuilding 115 kV Lines (100 miles with 5 substation upgrades)	$ 48	$ 97	-$ 4	$ 94

Note: The estimated construction cost used for the Winger-Wilton and Badoura-Wilton alternatives is $795,000/mile. The estimated construction cost used for rebuilding 115 kV lines is $430,000/mile. The estimated cost to construct the Project was further refined, however, to reflect the increased costs associated with the Project crossing forested and wetland areas. See Table 6.3-5 below for more detail on these increased costs. The estimated costs to upgrade substations for all the alternatives are $2,000,000 for a 230 kV substation and $1,000,000 for a 115 kV substation.

While the Bemidji-Grand Rapids Line has the highest installed cost, its higher efficiency yields significant electrical loss savings. Consequently, it is the second least-cost alternative when the total cost of ownership is considered. This economic analysis does not take into account that the alternatives do not provide equivalent load-serving capability, as demonstrated by the voltage stability and thermal analyses in subsection 5.4.2 above. The Badoura-Wilton 230 kV alternative provides only 73% of the load-serving capability of the Bemidji-Grand Rapids Line (see Table 5.4-2), while costing 94% as much as the Bemidji-Grand Rapids line (see Table 5.4-7). The other two alternatives provide significantly less load serving benefit for the Bemidji area.

To illustrate the actual cost-to-benefit profile for all four alternatives, a "Cost of Incremental Load Serving Capability" analysis was done.

5.4.5 Cost of Incremental Load Serving Capability Analysis

Using the incremental load serving capabilities reported for each transmission alternative in Table 5.4-7 as a base, both the installed cost and cumulative PVRR for each alternative was calculated on a per-kW basis. See Table 5.4.5 below.

Table 5.4-7 Incremental Costs of Load Serving Capability for Each Transmission Alternative

Transmission Alternative	Incremental Load Serving Capability (MW)	Installed Cost ($ millions)	Installed Cost ($/kW)	Cumulative Net PVRR ($ millions)	Cumulative PVRR ($/kW)
Bemidji-Grand Rapids 230 kV Line (68 miles with 2 substation upgrades)	275	$ 58	$ 211	$ 85	$ 310
Winger-Wilton 230 kV Line #2 (53 miles with 2 substation upgrades)	25	$ 46	$ 1,840	$ 92	$ 3,665
Badoura-Wilton 230 kV Line (48 miles with 2 substation upgrades)	200	$ 42	$ 210	$ 80	$ 400
Rebuilding 115 kV Lines (100 miles with 5 substation upgrades)	75	$ 48	$ 640	$ 94	$ 1,245

The Bemidji-Grand Rapids and Badoura-Wilton 230 kV Lines have comparable installed costs per kW ($211 vs. $210), but the net PVRR for the Badoura-Wilton Line is 29% higher than for the Bemidji-Grand Rapids Line on a cost per kW basis ($400 vs. $310).

More importantly, as noted in subsection 5.4.2(b) above, the superior voltage stability and thermal limits achieved by the Bemidji-Grand-Rapids Line means that its construction in the timeframe proposed by the Utilities effectively postpones any need for additional bulk transmission to the Bemidji area. Constructing any of the alternatives does not similarly forestall the necessity of building the Bemidji-Grand Rapids, however. For instance, upon completion of the next best alternative to the Project, the Badoura-Wilton line, the Utilities would have to immediately begin the permitting process to build the Bemidji-Grand Rapids Line so that it could be completed by the time it is needed. This would force ratepayers to unnecessarily absorb the cost of two lines over a short period of time when the cost of only one line is necessary.

5.4.6 Double Circuiting

As noted in Section 3.1, the Utilities' preferred corridor offers opportunities for the Project to be double circuited with existing 115 kV or 69 kV lines. This benefit of having portions of the Project share an existing right-of-way with another line must be balanced against the potential adverse impact of a single contingency taking out two lines rather than just one. In addition to this transmission reliability concern, double circuiting raises construction and maintenance issues that must be addressed. As previously noted, the feasibility of double circuiting portions of the Project with existing transmission and distribution lines will be addressed in detail in the Route Permit application for the Project.

5.4.7 Direct Current Alternative

The MPUC's rules require an applicant for Certificate of Need for an alternating current ("AC") transmission line to consider the possibility of constructing a direct current ("DC") line. A DC line is typically proposed for transmitting large amounts of electricity over long distances because there are considerably less line losses on a DC line than on an AC line. There are only two DC lines in existence in Minnesota, one of which is +/- 250 kV DC and the other is +/- 400 kV DC.

A DC line is not a realistic alternative in this situation. A line intended for local load serving purposes must be able to be readily tapped to serve customers. While this can be done with an AC line, a DC line requires two conversion systems: one to convert the AC electricity flowing through the DC line to DC current, and another to convert the DC current back to AC current that can be used by customers. Such converters would add dramatically to the cost of the Project, which the increase in line loss reductions could not offset. The economic justification for a DC line does not exist in this case.

5.4.8 Undergrounding

Undergrounding is an alternative that is seldom used for transmission lines. One major reason why is the expense. The cost range depends on such factors as the type of underground cable required, the extent of underground obstructions such as rock formations, the thermal capability of the soil, and the number of river crossings. The construction cost of locating the entire Project underground is estimated to be as much as 10 to 15 times greater per mile than if constructed as an overhead line as proposed. This is based on the cost range for an overhead 230 kV line of $675,000 to $915,000 per mile, while the cost range for the same voltage line underground is from $10 to $15 million per mile. These costs do not include the substations with large reactors that are necessary approximately every 20 miles to counteract the large line charging currents associated with undergrounded high voltage lines. In addition, there are increased line losses and maintenance expenses incurred throughout the useful life of an underground line that makes its cost over an overhead line even greater.

Because of the significantly greater expense associated with underground transmission construction, the undergrounding is limited to locations where physical circumstances allow no other alternative or where overhead construction is prohibited. Examples include congested downtown centers where there is no space available between city streets and adjacent buildings for adequate clearance.

While underground lines reduce visual impact and minimize surface impacts after construction (other than at the transition points where the line converts from being overhead to underground), there still are environmental consequences. The predominant environmental impact from the construction, operation, and maintenance of underground transmission lines arises from the need to obtain and maintain absolutely clear rights-of-way. The construction activities for an overhead transmission line are typically concentrated around the line's structures, while the areas between structures can be left relatively undisturbed except for the removal of vegetation that could interfere with the energized conductors. And a narrow pathway between structures is often all that is necessary to string the conductors. However, with underground construction the entire right-of-way needs to be cleared and is utilized for construction activities which must occur at every point along the right-of-way. This results in increased impacts to wetland areas due to the likely need to install an access road capable of supporting heavy construction equipment, trenching activities, and cable installation. In addition, high voltage underground conductors make use of soil moisture to assist in conductor cooling, so the right-of-ways need to be maintained free of woody vegetation to reduce soil moisture loss. A permanent road also must be maintained along the right-of-way to allow maintenance and repair.

Underground lines also present challenging service issues. While overhead lines are subject to more frequent outages then underground cables, service is usually quickly restored by automatic reclosing of circuit breakers resulting in a momentary outage of the line. The lower incidence of outages with underground cables is offset by those outages being longer in duration because it is not recommended to reclose circuit breakers until it is verified that a fault has not occurred on an underground cable. This is particularly difficult when the line is partially overhead and partially underground because the underground portion of the line prevents restoring outages of the overhead portion through reclosing operations.

A faulted underground line takes much longer to restore because of the difficulty in locating the fault and accessing the site to make repairs. It is generally not recommended to repair failures in high voltage extruded dielectric cables, but rather the portion of the cable containing the failure is replaced. Typically, this involves completely replacing the failed cable between two man-hole splice points, which are ordinarily located every 1,500 to 2,000 feet. Replacing failed cable involves bringing in heavy equipment, including cable reels weighing 30,000 to 40,000 pounds, during all seasons of the year. If the failure is in a splice, it may be feasible to make a repair at the splice location without having to replace large quantities of cable, but access is still required for equipment and personnel. If the fault occurs in a wetland area where all-season roads are not maintained, restoration can be delayed as matting is installed to gain access to the manholes involved in replacing the failed cable.

Despite the performance and cost drawbacks of undergrounding a transmission line, the DNR has requested the Applicants to consider that as an alternative at the points where the Project crosses the Mississippi River. The Applicants are analyzing this alternative and will discuss it in more detail in the Route Permit application for the Project.

5.4.9 Conclusion on Transmission Alternatives

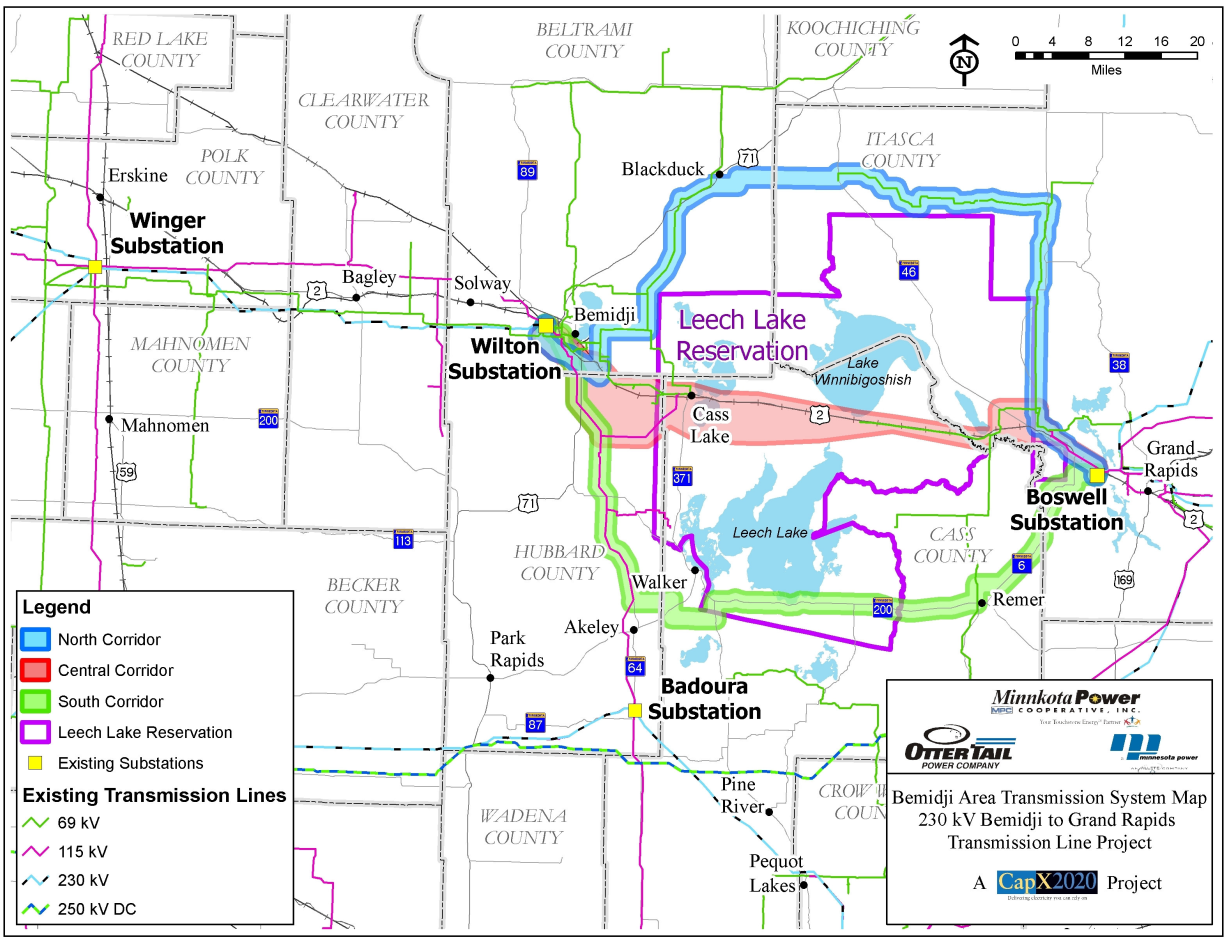
The best alternative to address the load-serving concerns of the area is a new 230 kV overhead AC transmission line. In comparison to the four new transmission alternatives that could address the issue, the Bemidji-Grand Rapids Line has the best electrical performance and best cost-to-benefit profile. For these reasons, the Utilities propose construction of the 230 kV Bemidji-Grand Rapids Line in the Utilities' preferred corridor to address the load-serving concerns in the Bemidji area and the North Zone of the Red River Valley.

SECTION 6 - ALTERNATIVE CORRIDORS

6.1 Alternative Corridors for the Project

After completing the studies that identify the Bemidji-Grand Rapids Line as the best transmission solution to the area's load serving inadequacies, the Utilities discussed their preferred corridor for the line through the Leech Lake Reservation with the Leech Lake Band of Ojibwe. Through those discussions, two alternative corridors were identified: a 116- mile corridor that runs to the north around the Leech Lake Reservation ("Northern Corridor"); and a corridor that runs through a southern portion of the Reservation ("Southern Corridor"). See Figure 6.1 below.

Figure 6.1 Alternative Corridors for the Project



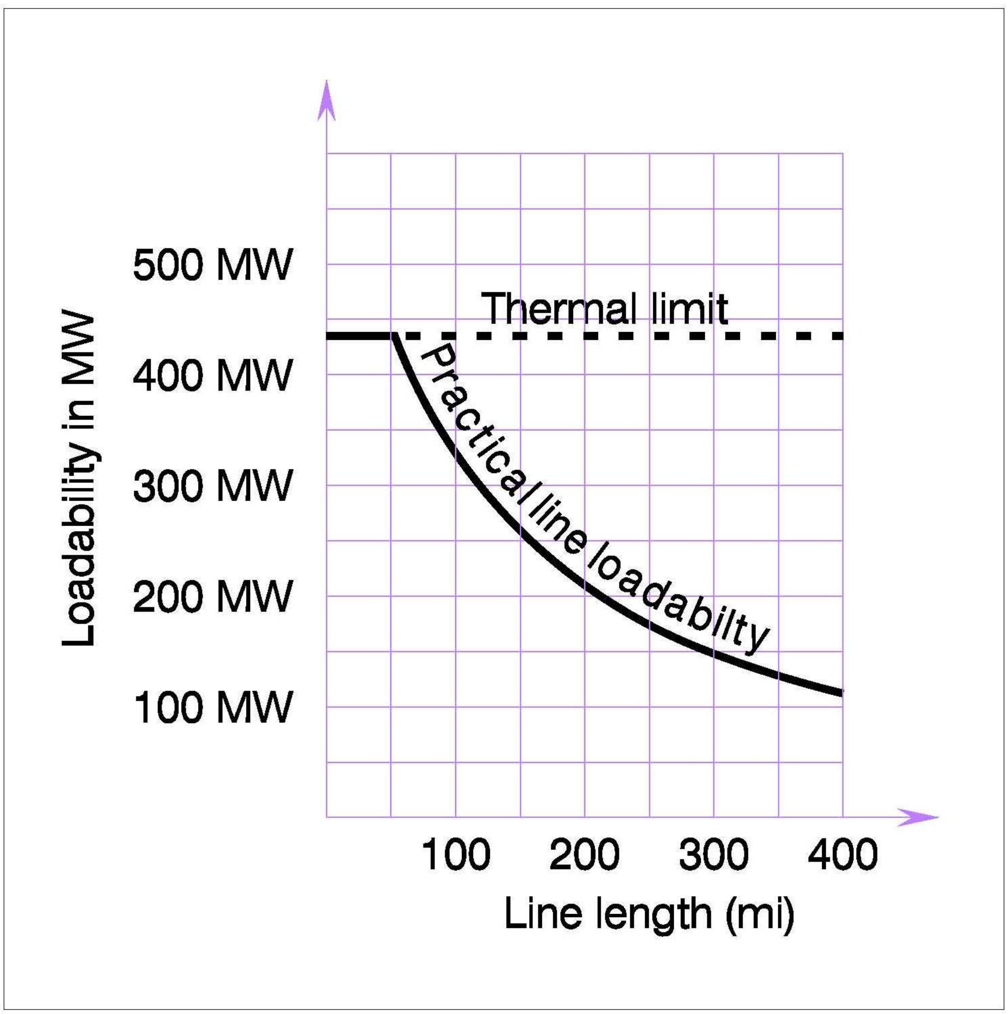
Upon examining the electrical performance of the line along the two alternative corridors, as well as the costs of construction, the Utilities concluded that neither alternative is preferred. A summary of the analysis is provided below.

6.2 Electrical Performance Issues

Locating the route for the Bemidji-Grand Rapids Line in the Utilities' preferred corridor (also referred to as the "Central Corridor") provides more reliable electric service for the Bemidji area than the alternative corridors because it maximizes the load serving ability of the line and it provides the most flexibility to make other reliability improvements in the area, most notably at Cass Lake.

A transmission line's ability to transport increasing amounts of electric power, referred to as the line's loading limit, is generally constrained by the line's thermal limit. When a transmission line is short, the impedance of the conductor is smaller and therefore the line can be loaded up to its capacity, or thermal limit, and still maintain stable voltage (steady state stability). The longer the transmission line becomes, however, the higher the impedance of its conductor and the lower its ability to maintain acceptable steady state voltage. In short, as a line's length increases its loading limit becomes less than its thermal limit, resulting in a longer line providing less load-serving capacity than a shorter line of the same voltage.

Figure 6.2 Impact of Line Length on Loading Limits
(Generic 230 kV Transmission Line)



The Southern Corridor is almost half again as long as the Central Corridor (99 miles vs. 68 miles), resulting in the loading limit of a 230 kV line in the Southern Corridor being about 85% of the limit of a 230 kV line in the Utilities' preferred corridor. The Northern Corridor is even longer (116 miles), which results in a 230 kV line's loadability in that corridor being only around 75% of what it would be in the preferred corridor. The reduced loading limits of transmission facilities in the alternative corridors directly diminishes the lines' ability to effectively address post-contingent voltage concerns in the Bemidji area and reduces the load serving capability of the line.

A further consideration is that there is expected to be a need for additional electric power support in the vicinity of Cass Lake in the future. Cass Lake is located southeast of Bemidji in the Leech Lake Reservation. If the existing 115 kV line between Bemidji and the Nary Switch southeast of Bemidji experiences an outage, Cass Lake has only one electrical source remaining, which is from Badoura to the south. Studies show that with any significant growth in the Cass Lake area it will be difficult to serve Cass Lake from Badoura alone. The Utilities' preferred corridor passes very near Cass Lake, which is midway between the Reservation's northern and southern borders, making available low-impact alternatives to reinforce electric service there when the need arises. This could involve segmenting the new line with a 230/115 kV substation located near Cass Lake, or adding a 115 kV circuit between Bemidji and Cass Lake as an underbuild on the proposed 230 kV line. Either of these alternatives can be accomplished with minimal impact on right-of-way requirements, and at relatively low expense. To comparably improve Cass Lake service if the Bemidji-Grand Rapids Line is located in the Southern or Northern Corridors, it would be necessary to build a new 10- to 12-mile 115 or 230 kV line in new right-of-way to connect either corridor to Cass Lake.

Finally, system design considerations do not support locating the route for the Bemidji-Grand Rapids Line in the Southern Corridor. Large portions of the Southern Corridor overlay the route of the existing Wilton-Bemidji-Nary-Laporte-Akeley 115 kV line. Locating the Bemidji-Grand Rapids Line along the same route as the Wilton to Akeley 115 kV line would result in 2 of the 4 transmission facilities for the Bemidji area being directed through the same geographic region south of Bemidji. Choosing to configure the system like this heightens the risk that the Bemidji-Grand Rapids and Wilton-Akeley transmission lines could both experience an outage from the same weather-related event along this 45-mile corridor. NERC recognizes the loss of all circuits within a common right-of-way as a credible contingency that must be considered in transmission planning studies. See NERC Standard TPL-004-0, Category D.7.

6.3 Cost Issues

The Utilities conducted demand and energy loss and cost of ownership analyses of the Bemidji-Grand Rapids Line in the three corridors. The same methodologies and cost assumptions were used for these analyses as those discussed in subsections 5.4.3 and 5.4.4 above.

The demand loss reductions of the three corridors are shown in Table 6.3-1 below for both summer and winter peak conditions.

Table 6.3-1 Demand Loss Reductions for Each Corridor
Eastern Interconnection

Corridor	Peak Winter Demand Loss Reduction (MW)	Peak Summer Demand Loss Reduction (MW)
Preferred Corridor (68 miles)	23.9	5.2
Southern Corridor (99 miles)	20.6	4.7
Northern Corridor (116 miles)	19.2	4.3

The Northern and Southern Corridors yield smaller loss reductions (19 and 21 MW, respectively) than the Utilities' preferred corridor. The alternative corridors' inferior performance is due to their greater lengths, and therefore higher impedance, which result in less power flow on the line and consequently offer less loading relief for existing transmission sources in the Bemidji area.

The annual summer peak demand loss reductions for the corridors were translated into demand-related cost savings. The results are in Table 6.3-2 below, which shows the savings of locating the Project's route in the preferred corridor are 11% greater than if the route is located in the Southern Corridor, and 21% greater than if the route was located in the Northern Corridor.

Table 6.3-2 Annual Demand Loss Reduction Savings for Each Corridor
Eastern Interconnection

Corridor	Demand Loss Reduction Savings ($ Thousands)
Preferred Corridor (68 miles)	$ 499
Southern Corridor (99 miles)	$ 451
Northern Corridor (116 miles)	$ 413

Annual energy losses and associated cost savings were also calculated for the three corridors, as shown in Table 6.3-3 below.

Table 6.3-3 Annual Energy Loss Savings for Each Corridor
(at $50/MWh)

Corridor	Peak Loss Reduction (MW)	Loss Factor (%)	Equivalent Hourly Loss Savings (MW)	Annual Loss Savings (MWh)	Annual Loss Savings @ $50/MWh ($ thousands)
Preferred Corridor (68 miles)	23.9	41.5	9.92	86,886	$ 4,344
Southern Corridor (99 miles)	20.6	41.5	8.55	74,889	$ 3,744
Northern Corridor (116 miles)	19.2	41.5	7.97	69,800	$ 3,490

The Utilities' preferred corridor is projected to allow annual energy loss savings of over $4.3 million, which is 16% greater than the loss savings of the Southern Corridor, and 24% greater than those of the Northern Corridor.

The cumulative lifetime economic value of the demand and energy loss reductions was calculated for each corridor. Table 6.3-4 below shows the present value of the demand and energy losses by corridor, which indicate that locating the route for the Project in the preferred corridor offers the greatest opportunity to realize loss savings.

Table 6.3-4 Annual and 40-Year Cumulative Present Value of Loss Reductions for Each Corridor

Corridor	Annual Savings ($ Thousands)			Cumulative Present Value ($ Millions)
	Demand Savings	Energy Savings	Total Savings	
Preferred Corridor (68 miles)	$ 499	$4,344	$ 4,843	$ 31.9
Southern Corridor (99 miles)	$ 451	$ 3,744	$ 4,195	$ 27.7
Northern Corridor (116 miles)	$ 413	$ 3,490	$ 3,903	$ 25.7

To put the loss savings of the corridors into perspective relative to the construction costs of the line for each corridor, the cumulative present value of the revenue requirements to construct the line in each corridor was calculated based on both the construction costs and loss savings associated with the corridor. As explained in the note to Table 5.4-6 above, the cost of constructing a line increases when it traverses forested or wetland areas. Table 6.3-5 below shows the cost of constructing the Bemidji-Grand Rapids Line in each of the three corridors based on terrain.

Table 6.3-5 Project Construction Costs for Each Corridor

Cost Factor	Central Corridor		Southern Corridor		Northern Corridor	
	Length (miles)	Cost ($ million)	Length (miles)	Cost ($ million)	Length (miles)	Cost ($ million)
Base 230 kV Line Cost	68	$46.9	99	$68.2	116	$79.9
Wetland adder	18	3.5	13	2.5	29	5.7
Wetland Mats	3	3.7	3	3.7	3	3.7
Forest adder	33	4.0	63	7.7	60	7.3
Total Line Cost		$58.1		$82.1		$96.6

Table 6.3-6 below shows the PVRR to construct the Bemidji-Grand Rapids Line in each corridor, based on the line construction costs in the above table plus an estimated $2.5 million for upgrades to the Wilton and Boswell Substations. The $2.5 million is based on an estimate of the actual substation upgrade work necessary for the Bemidji-Grand Rapids 230 kV Line, not the generic $2 million/substation upgrade used in the transmission alternatives analysis in subsection 5.4.4 above.

Table 6.3-6 Cumulative Present Value of Revenue Requirements (PVRR) for Each Corridor
(Including Value of 40-Year Loss Savings)

Corridor	Installed Cost ($ millions)	Cumulative PVRR ($ million)		
		Capital Related PVRR	Loss Savings	Net PVRR
Preferred Corridor (68 miles)	$ 60.6	$ 122	-$ 32	$ 90
Southern Corridor (99 miles)	$ 84.6	$ 170	-$ 28	$ 143
Northern Corridor (116 miles)	$ 99.1	$ 200	-$ 26	$ 175

The Utilities' preferred corridor has a PVRR of $90 million, with the PVRR for the Southern Corridor being 59% higher and the PVRR for the Northern Corridor being 94% higher.

6.4 Environmental Issues

The Utilities prefer the Central Corridor because it allows the optimum performance of the proposed transmission line while minimizing impacts to social, economic, and environmental resources. As previously noted, however, at this stage not all of the environmental resources and impacts have been identified to the extent required for final route selection. Additional agency and stakeholder input, field surveys, and analysis must still be conducted as part of the joint federal/state environmental review process to identify the best route for the Project.

The Utilities have conducted a preliminary environmental review of the three corridors, however, referred to as a Macro Corridor Study ("MCS"). This preliminary review was conducted in accordance with RUS guidelines for federal environmental review of a high voltage transmission line. The Applicants' March 2008 draft MCS submitted to the RUS is included in Appendix G. The draft MCS contains an overview of the types of land use, physiography, hydrology, vegetation, and wildlife in each of the three corridors. The draft MCS indicates that it is preferable to locate the route for the Bemidji-Grand Rapids Line in the Central Corridor in light of performance, cost, and environmental considerations. See MCS in Appendix G.

As the identification and development of transmission line routes proceeds, areas where avoidance is not possible will be identified, and impact minimization and/or mitigation strategies will be developed. Specific avoidance areas include areas where transmission line development is prohibited because of federal, state, or local regulations or undesirable because of conflicts with existing land use/development or land features. Within the Central Corridor, the following resources would be avoided where possible, and where they cannot be avoided, impact minimization and or mitigation will be necessary:

- Recreational resource areas – trails, campgrounds, water access points
- Hole-in-Bog Peatland Scientific and Natural Area
- Bemidji Slough and Wolf Lake Wilderness Management Areas
- Ecologically important areas
- Culturally important areas
- Wetlands and other water resources
- Deer River and Bemidji Airports
- Active gravel mining operations

6.5 Conclusion on Alternative Corridors

The total cost of locating the route for the Project in the Utilities' preferred corridor is substantially lower than if it were located in the alternative Northern or Southern Corridors. This cost differential, coupled with the superior electrical performance achieved if the line is located in the preferred corridor, demonstrates that it is a better choice than the alternative corridors. The Utilities' preliminary environmental analysis of the impact of routing the Project in each of the three corridors supports the conclusion that the Central Corridor is preferable.

SECTION 7 - APPLICATION OF CRITERIA

7.1 Denial Would Adversely Affect the Energy Supply

The Red River Valley is a geographically large area with limited local generation. As MISO observed in its 2006 Transmission Expansion Plan, there are serious voltage collapse concerns because of the hundreds of category C contingencies that occur in the area. These concerns are heightened if there is an outage of more than one source to the area; load shedding is often the only way to avoid voltage collapse and restore the system's performance to acceptable levels.

In addition, load growth forecasts show the peak load serving limit of the local transmission system is being reached due to load growth and associated growth in peak demand. It is estimated that winter peak demand in the Bemidji area will increase to 296 MW by 2011/2012, 76 MWs above the current system's peak load serving capability. By 2011, any shortfall in load serving capability can no longer be handled by forcing the operation of local generation and increasing the local power system's reactive power supply, as the Utilities are now planning on doing. New transmission will be necessary to maintain voltage stability in the event of single and double contingencies.

7.2 There Is No Reasonable and Prudent Alternative

The Utilities have studied no-build, new generation, and new transmission alternatives to deal with transmission system deficiencies with increasing customer load in the Bemidji area. This Certificate of Need application demonstrates that the no build alternative for dealing with the growth is not a responsible alternative for the Utilities given their obligation to provide safe and reliable electrical service to their customers. While the execution of DSM and CIP programs will limit the growth of customer demand for more energy, and existing system upgrades by the Utilities can extend system reliability for the near-term, future load growth is nevertheless projected to reach a point where either new generation or new transmission will be necessary to meet anticipated demand.

Adding new generation in the Red River Valley, however, is not a practical alternative to improving the load serving capability of the electric system. The reliability and economics of adding small, intermediate, or large bulk generation, or distributed generation, are not favorable in comparison to the alternative of adding new transmission. In the case of distributed generation, there is the added problem that the high number of generation units must be strategically located to put power on the system at the points required to improve reliability, and obtaining the required approvals to place such a high number of small generation units is unlikely. If large generators were added, generation outlet requirements for the area would increase, requiring additional transmission that the added generation was intended to avoid. Intermediate generation has even greater capital investment and operational costs than small generation, and also contributes to an increased need for generation outlet facilities as the addition of large generation would.

The best alternative to address the load-serving concerns of the area is new transmission. In comparison to all the transmission alternatives evaluated in the numerous studies conducted over the last seven years, the Bemidji-Grand Rapids Line has the best electrical performance and best cost-to-benefit profile. For these reasons, the Utilities propose construction of the 230 kV Bemidji-Grand Rapids Line in the Utilities' preferred corridor to address the load-serving concerns in the Bemidji area and the North Zone of the Red River Valley. There is no reasonable and prudent alternative to construction of the Bemidji-Grand Rapids Line to address the voltage reliability and load serving deficiencies in the Bemidji area and the North Zone of the Red River Valley for the long term.

7.3 The Project Will Protect the Environment and Provide Benefits

The Utilities have conducted a preliminary environmental review of three alternative corridors for the Project and believe that it is preferable to locate the Bemidji-Grand Rapids Line in the Central Corridor in light of performance, cost, and environmental considerations. At this stage, however, not all of the environmental resources and impacts have been identified to the extent required for final route selection. Additional agency and stakeholder input, field surveys, and analysis must still be conducted as part of the joint federal/state environmental review process to identify the best route for the Project and what, if any, mitigation measures must be taken to protect the environment.

7.4 The Project Will Comply with All Applicable Requirements

All other permits and approvals that may be required for the Project have been identified in Section 2.7, and Sections 3.6 through 3.15 detail the standards that the Applicants must meet for the acquisition, construction, operation, and maintenance of the Project. The Applicants have committed to meeting all of these requirements and explained the processes and practices that will be followed to do so.

7.5 Conclusion

The Applicants, Otter Tail Power Company, Minnesota Power, and Minnkota Power Cooperative, respectfully request the Commission issue a Certificate of Need authorizing construction of an approximately 68-mile 230 kV transmission line between the Wilton Substation west of Bemidji, Minnesota and the Boswell Substation in Cohasset, northwest of Grand Rapids, Minnesota.

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